Concept Memo: Economic Analysis of Oil and Gas Activities in Cook Inlet, Alaska
Briefing Paper for Ephraim King (1 May 2009)

Overview

- Cook Inlet is a mature oil and gas field. Most of the 13 active platforms in Cook Inlet were constructed from 1964 to 1968. The most recently constructed platform (Osprey, Pacific Energy Resources) began operation in 2000 and does not discharge (disposal of cuttings and produced water via re-injection).

    - Chevron (9 active platforms)
    - XTO (2 active platforms)
    - Pacific Energy Resources (1 active platform)
    - ConocoPhillips (1 active platform)

- In the final 1996 rule EPA allowed coastal operators in Cook Inlet, Alaska, to discharge and set the limits for coastal Cook Inlet equal to the Offshore subcategory for produced water and aqueous drilling fluids and cuttings. EPA did not identify injection of drill cuttings and produced water as the basis for BAT limitations or NSPS due to:

    - Uncertainties regarding the availability of geologic formations suitable for injection;
    - Limited availability to onshore disposal for drilling wastes; and
    - Potential economic impacts (EPA's economic analyses predicted that 1 platform would close and 2 additional platforms would suffer severe economic impacts under the zero discharge option).

Economic Factors Affecting Production Decisions

- Oil and gas production in Cook Inlet has peaked and is now declining. Below is a summary of the current state of the Cook Inlet field (2008) as compared to the reference year for the Coastal ELG rulemaking (1992).

	2008	**1992**
Number of Active Platforms	13	13
Oil Production	4 million bbls	13.6 million bbls
Natural Gas Production	48 million Mcf	128.7 million Mcf
Active Oil and Gas Wells	165	237
Produced Water Volume	35.6 million bbls	47 million bbls

- The operating costs for oil field services from 1992 to mid 2006 (last year for which producer price index data are available for this subsector) shows that costs have roughly doubled in the intervening years.

- As shown in the following table and in Table 1, operator revenues (in $2008) have declined by nearly 50 percent. Table 2 provides more detail on EPA assumptions for the re-injection option for the 1996 Coastal ELG rulemaking and the ratio of incremental annualized costs of re-injection to production value for specific facilities.

	2008	**1992**
Price of Natural Gas	$5/Mcf	$1.57/Mcf
Price of Oil	$42/bbl	$14.50/bbl
Value of Production (Millions, $2008)†	$412	$781
Incremental Costs of Zero Dicharge (Millions, $2008)	$46.6	$48
Ratio of Incremental Costs to Production Value	11%	6%

† Note: This production value does not include the value of production from Osprey ($3.5 million), which already operates as a zero discharge facility. Additionally, Chevron's Dillon platform has shut-in after 1996 and the final rule's annualized compliance costs for zero discharge ($1.5 million) are not included in the 2008 estimate of zero discharge.

- This assessment does not account for the recent shut-in of all of Chevron's production from their platforms due to the recent activity of the Mt. Redoubt volcano (March 22, 2009). This volcanic activity forced Chevron to close the Drift River oil terminal, which is located at the mouth of a river that flows from Mt. Redoubt, and stop production from their platforms due to lack of storage space for their oil. The Drift River oil terminal is the only means for shipment of oil from the west side of Cook Inlet. Chevron is not optimistic that production from the some of the shut-in wells can be restarted, mostly those in the Granite Point field.[1] The Osprey platform is also currently shut in.

- Most of the incremental capital costs associated with the Coastal ELG re-injection option are related to the costs of piping treated produced water from onshore treatment facilities to injection wells at the platforms for water-flooding operations (enhanced oil recovery). See pie charts at the end of this paper. It is not known whether treatment of produced water at the platforms (prior to re-injection), instead of sending produced water back and forth to shore, is available with current technology for the platforms that utilize onshore treatment facilities.

Future Oil and Gas Exploration and Development

- Information was found only for the Cook Inlet Basin as a whole. The most recent estimate (2006) for proved oil and gas reserves are approximately 94 million barrels (bbls) and 1.3 trillion cubic feet (Tcf), respectively.[2,3] Proved reserves are those reserves

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[1] See http://www.rigzone.com/news/article.asp?a_id=75471.
[2] See http://www.cookinletoilandgas.org/PowerPoint%20Presentations/PDF%20Versions/AOGCC%20Conference%2009.20.06.pdf
[3] See http://www.gasandoil.com/goc/news/ntn91167.htm.

claimed to have a reasonable certainty (normally at least 90% confidence) of being recoverable under existing economic conditions and using existing technology. Therefore, oil and gas production in Cook Inlet may last a decade or more under existing economic conditions and using existing technology.

- Since the Osprey exploration and development in 2000, the exploration activity in Cook Inlet has been undertaken from onshore drilling locations. However, there are two possible areas of interest.
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    - In 2008, Pacific Energy Resources contracted with Blake Offshore for a drilling rig to be brought to Cook Inlet.[4] The company wishes to drill in its Corsair Unit (see Figure 1). Also interested in using this rig is Renaissance Alaska, LLC, which is interested in working its Northern Lights field (formerly Arco's Sunfish, which was abandoned in the early 1990s). Renaissance believes that modern technology will be able to better produce this field. Originally, these activities were planned for the 2009-2010 timeframe. To our knowledge, however, the rig is not yet underway.

    - Figure 1 also shows a variety of exploration activities, most of which are associated with land based projects; however Chevron undertook some 3D seismic studies in the Granite Point Field in 2007.

Summary

- There are fewer wells operating (about one-third fewer) and produced water volumes have dropped significantly (23 percent), which should mitigate some of the cost increases. However, operating margins in Cook Inlet, however, have likely become significantly smaller in the intervening years.

- This assessment does not account for the extreme volatility in oil and gas prices seen over the last year or so. Such an assessment conducted last summer, for example when the price of oil rose to a record of $147.27, might have indicated a much more optimistic situation regarding operating margins.

- Also of interest is the volume of water production compared to hydrocarbon production. Platforms with a low ratio of water to hydrocarbon production will be in a better position economically to deal with any increased costs. As Table 1 shows, the most sensitive platforms to any changes in costs are likely to be those with above average water to production ratios: Grayling, King Salmon, and Dolly Varden, all of which are associated with the Trading Bay onshore treatment facility.

- If oil and gas prices remain roughly the same as current prices and if Chevron and Pacific Energy Resources platforms remain shut in for an extended period, and some production is permanently lost due to volcanic activity, the affordability of increased produced water costs might be an issue for some platforms.

[4] http://www.istockanalyst.com/article/viewiStockNews/articleid/2803079

- The most important factor affecting the financial viability of the Cook Inlet platforms is the longer-term trend of oil and gas prices. The downturn of the economy will likely depress oil and gas prices over the next few years. Assuming an economic recovery in 2010 and continuing to 2013, there should be an increase, potentially a doubling of oil and gas prices by the year 2015. The following passage from DOE's 2009 Annual Energy Outlook is worth quoting at length:

  "The reference case assumes that growth in the world economy and liquids demand will recover by 2010, with growth beginning in 2010 and continuing through 2013, when world demand for liquids surpasses the 2008 level. In the longer term, world economic growth is assumed to be roughly constant, and demand for liquids returns to a gradually increasing long-term trend. As the global recession fades, oil prices (in real 2007 dollars) begin rebounding, to $110 per barrel in 2015 and $130 per barrel in 2030."

  Source: U.S. DOE, 2009. "Annual Energy Outlook 2009," DOE/EIA-0383, March 2009.

Table 1. Summary Information on Cook Inlet Platform Production (2008)

Platform	Company	Treatment Facility	Active Wells	Total Wells	Total Oil 2008 (bbls)	Total Gas 2008 (Mcf)	Total Water 2008 (bbls)	BOE	Bbl Water/ BOE	Estimated Value of Production
Anna	Chevron	Platform	13	15	416,049	344,034	83,031	478,749	0.173433	$ 19,194,228
Baker	Chevron	Platform	1	14	-	8,217	-	-	NA	$ 41,085
Bruce	Chevron	Platform	7	12	186,050	203,913	45,417	223,213	0.203469	$ 8,833,665
Dillon	Chevron	Platform	-	9	-	-	-	-	-	$ -
Dolly Varden	Chevron	Trading Bay	19	37	485,960	340,697	6,851,084	548,052	12.5008	$ 22,113,805
Granite Pt.	Chevron	Granite Point	7	11	359,620	304,728	101,008	415,156	0.243301	$ 16,627,680
Grayling	Chevron	Trading Bay	20	35	608,363	1,752,059	12,876,861	927,674	13.88081	$ 34,311,541
King Salmon	Chevron	Trading Bay	14	26	436,934	181,395	8,440,810	469,993	17.95944	$ 19,258,203
Monopod	Chevron	Trading Bay	20	34	316,217	418,372	1,169,371	392,465	2.979556	$ 15,372,974
North Cook (Tyonek A)	ConocoPhillips	Platform	12	15	-	23,178,822	71,691	4,224,316	0.016971	$115,894,110
Osprey	Pacific Energy Resources	Platform*	3	5	80,159	21,111	207,305	84,006	2.467727	$ 3,472,233
Spark	Marathon	Granite Point	-	6	-	-	-	-	-	$ -
Spurr	Marathon	Granite Point	-	8	-	-	-	-	-	$ -
Steelhead	Chevron	Trading Bay	22	28	265,795	20,731,535	5,127,299	4,044,096	1.267848	$114,821,065
XTO-A	XTO	E. Foreland	15	17	745,172	170,992	257,915	776,335	0.332221	$ 32,152,184
XTO-C	XTO	E. Foreland	12	16	320,230	58,823	388,545	330,950	1.174028	$ 13,743,775
Total			165	288	4,220,549	47,714,698	35,620,337	12,915,005	2.758058	$415,836,548

*Assumed; needs confirmation.

Source: Alaska Oil and Gas Conservation Commission Database

Notes:

Assumed value of oil computed as 2006 wellhead price (Cook Inlet Oil) reported by AK Dept. of Revenue minus average spot price 2006 West Coast oil to approximate differential (approx. $1.40)

Average first 3 months 2009 West Coast oil spot price (approx. $43) minus 2006 differential used to compute estimated 2009 wellhead price of approx. $42/bbl.

Assumed value of gas computed as 2009 first quarter prevailing price for Cook Inlet gas delivered (minus assumed differential of $1.50 for transportation, compression, etc.

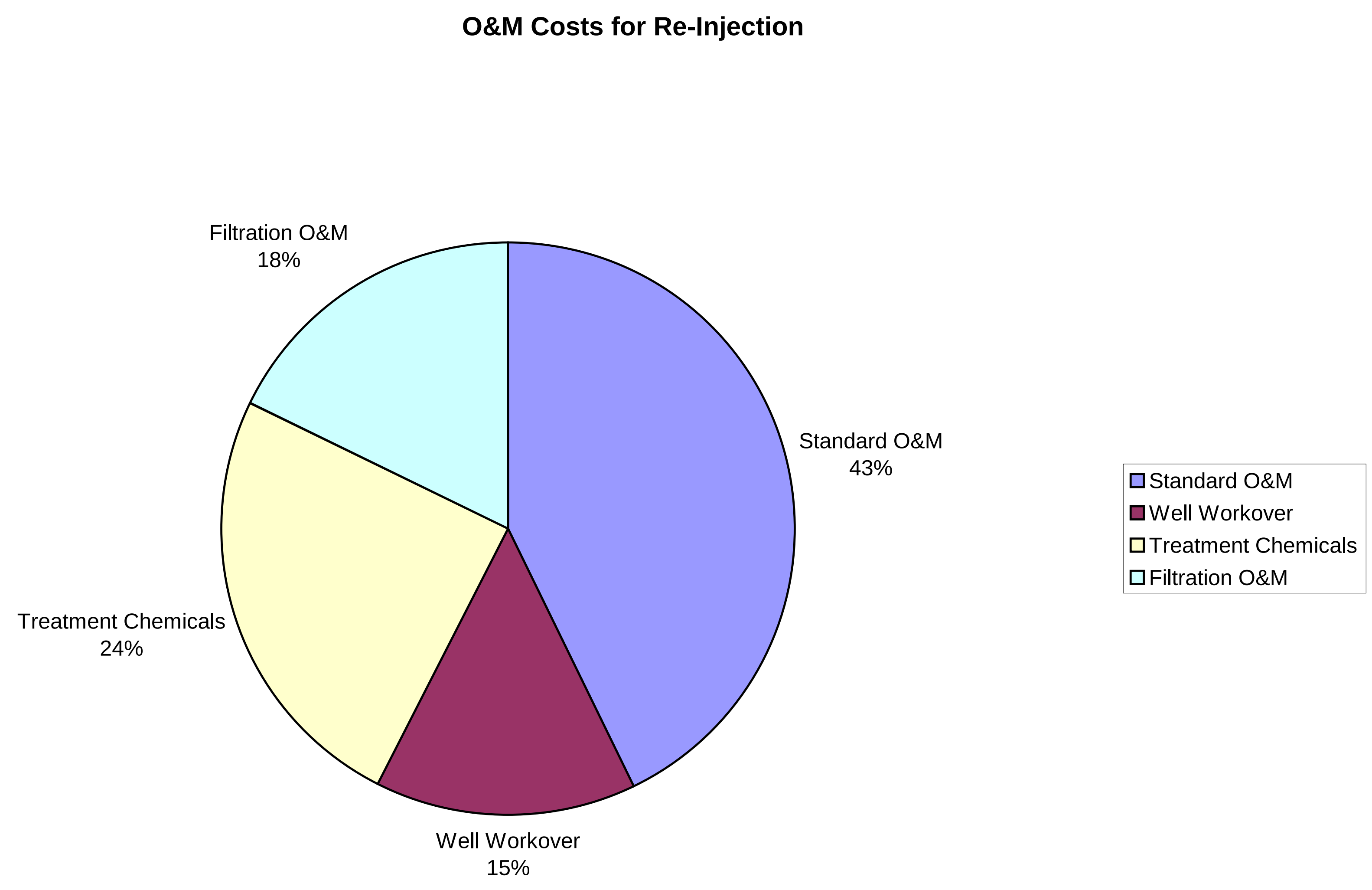
First quarter 2009 gas price is $6.50, yielding $5.00 estimated wellhead price.

Table 2. Conceptual Information on Re-injection Treatment Costs

Cost Category	Trading Bay Treatment Facility (1) (Chevron)	Granite Point Treatment Facility (2) (Chevron)	East Foreland Treatment Facility (3) (XTO)	Anna (Chevron)	Dillon (Chevron)	Bruce (Chevron)	Baker (Chevron)	Tyonek (Conoco Phillips)	TOTAL
Capital Costs (1995$)									
Installed Equipment	$9,862,859	$1,993,878	$5,416,656	$1,563,581	$1,682,569	$1,305,920	$1,563,581	$1,284,652	$24,673,696
Main Equipment Building	$325,532	$325,532	$325,532	$0	$0	$0	$0	$0	$976,596
Engineering (10%)	$1,018,839	$231,941	$574,219	$156,358	$168,257	$130,592	$156,358	$128,465	$2,565,029
Contingency (15%)	$1,528,259	$347,911	$861,328	$234,537	$252,385	$195,888	$234,537	$192,698	$3,847,543
Ins. + Bonding (4%)	$407,536	$92,776	$229,687	$62,543	$67,303	$52,237	$62,543	$51,386	$1,026,011
Pipeline (from onshore treatment facilities to platforms)	$33,143,900	$0	$15,297,055	$0	$0	$0	$0	$0	$48,440,955
Platform Modification	$4,830,901	$1,058,958	$1,340,690	$178,388	$225,958	$95,140	$178,388	$339,786	$8,248,209
Injection Equipment	$0	$70,451	$0	$0	$0	$185,194	$0	$185,194	$440,839
Injection Well	$0	$1,481,625	$0	$0	$0	$2,627,795	$0	$2,627,795	$6,737,215
Total Capital Costs (1995$):	$51,117,826	$5,603,072	$24,045,167	$2,195,407	$2,396,472	$4,592,766	$2,195,407	$4,809,976	$96,956,093
Total Capital Costs (2008$):	$77,643,783	$8,510,607	$36,522,635	$3,334,643	$3,110,375	$6,976,035	$3,334,643	$7,305,959	$147,268,348
Capital Costs (1995$)									
Standard O&M	$5,111,783	$405,100	$2,404,517	$219,541	$239,647	$177,978	$219,541	$199,699	$8,977,806
Well Workover	$2,400,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$3,100,000
Treatment Chemicals	$4,611,467	$30,966	$140,000	$44,433	$103,867	$3,966	$195,433	$1,000	$5,131,132
Filtration O&M	$3,060,031	$20,549	$97,499	$29,485	$250,205	$163,913	$129,684	$644	$3,752,010
Total O&M Costs (1995$):	$15,183,281	$556,615	$2,742,016	$393,459	$693,719	$445,857	$644,658	$301,343	$20,960,948
Total Capital Costs (2008$):	$23,062,158	$845,453	$4,164,897	$597,632	$1,053,702	$677,220	$979,183	$457,715	$31,837,960
Annualized Costs									
Discount Rate (7%)	7	7	7	7	7	7	7	7	7
Number of Years Over Which the Value is Annualized (15 yrs)	15	15	15	15	15	15	15	15	15
Annualized Costs (1995$):	$20,795,744	$1,171,802	$5,382,046	$634,503	$956,839	$950,118	$885,702	$829,453	$31,606,206
Annualized Costs (2008$):	$31,587,028	$1,779,871	$8,174,886	$963,758	$1,395,205	$1,443,151	$1,345,308	$1,259,870	$46,612,028
Estimated Value of Production (2008$)	$205,877,588	$16,627,680	$45,895,959	$19,194,228	-	$8,833,665	$41,085	$115,894,110	$412,364,315
Ratio of Incremental Costs to Production (2008$):	15%	11%	18%	5%	N/A	16%	3274%	1%	11%

Notes:

(1) Trading Bay Treatment Facility currently collects and treats produced water from the following Unocal platforms: Dolly Varden, Grayling, King Salmon, Monopod, Steelhead
(2) Granite Point Treatment Facility currently collects and treats produced water from Chevron's Granite Point platform. Marathon's Spark and Spurr platforms have been shut-in since at least 1992 (reference year for Coastal ELGs)
(3) The East Foreland Treatment Facility currently collects and treats produced water from XTO's "A" and "C" platforms.
(4) Pacific Energy Resources Osprey Platform operates as a zero discharge facility (i.e., no incremental costs associated with zero discharge).
(5) Capital and O&M costs were inflated from 2005 to 2008 using the ENR CCI (8310/5471).
(6) Chevron's Dillon Platform went inactive after the 1996 Coastal ELGs.


O&M Costs for Re-Injection
Filtration O&M
18%
Standard O&M
43%
Treatment Chemicals
24%
Well Workover
15%
Standard O&M
Well Workover
Treatment Chemicals
Filtration O&M

Captial Costs for Re-injection